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# **Argyll Field; the first oil field to be developed on the UK continental shelf**

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## **Abstract**

In June 1975, oil from the Argyll Field became the first to be produced from the UK North Sea. Hamilton Brothers, a US company had beaten BP and their giant Forties Field into production. Seventeen years later the Argyll Field was abandoned with all production facilities removed. The first chapter of UK offshore oil production closed. Argyll lay forgotten by most and unwanted by all.

A new millennium dawned and with it two new companies Acorn Oil and Gas and Tuscan Energy. Both had identified Argyll as a potential field redevelopment. An alliance formed. The UK's Department of Industry was approached with a request to relicense the Argyll Field out of round in order to redevelop the field. No company previously had sought to obtain a licence for production rather than exploration. It worked, as did the quest by both companies to obtain equity and debt funding.

In September 2003 the first well was drilled on the newly renamed Ardmore Field since abandonment (Gluyas *et al*, 2005). It flowed unaided at 20,000 barrels of dry oil per day; significantly in excess of expectation. However, after two months of sustained high rate the well cut water. With a second well on stream production peaked at 28,000 barrels of oil for one day before the facilities, designed for 50,000 barrels of fluid per day, tripped-out. All was not well; during the next two years, facilities and well issues limited production. Debt was not adequately serviced and funding withdrawn. In mid-2005 the field was abandoned

again. Five from an expected 25 million barrels was produced. Argyll/Ardmore chapter 2 ended but the story was not yet done. By 2013 EnQuest had acquired the licence and drilled 6 wells. Production restart began in late 2015. Chapter 3 has opened for the newly named Alma Field.

## **Introduction**

The Argyll Field in UK Block 30/24 was the first oilfield to come on stream in the UK North Sea. It began to export oil via tanker loading in June 1975 and continued in production, albeit with a downgrade to a smaller production vessel until 1992. During the 17 years it was on stream 72.6 million barrels of light, 37°API crude was produced but by 1992 with an oil price of under \$20 per barrel and daily production dipping below 6000bpod, the wells were plugged and the field was abandoned.

By the mid-1990s the data from the field was all released into the public domain and these data had become classic teaching material at Imperial College London. They were used extensively on the Petroleum Geology masters course. It was while listening to student presentations at Imperial College that one of the authors (JG) became familiar with the field. JG had then just returned from a posting to Venezuela where he worked on the redevelopment of geriatric fields. Might it be possible that Argyll could be redeveloped? Work began. Although abandoned in 1992, it was clear from the outset that Argyll was without doubt a field behind its time. The one near analogue for Argyll, the Auk Field of Block 30/16 had kept pace with technology developments through the 1970s to 1990s. Auk has Zechstein and Rotliegend reservoirs but no Devonian pay intervals. It was developed with a traditional platform rather than the sub-sea wells used on Argyll. Auk also had 3D

seismic coverage, high angle wells, water injection and modern well completions. Argyll did not.

Ten years after Argyll was abandoned (2002), two new oil companies, Tuscan Energy and Acorn Oil and Gas were awarded the licence to redevelop the Argyll Field. Since Argyll had ceased to exist in a legal sense it was renamed as Ardmore. The first Ardmore well was drilled in the summer of 2003 and oil flowed in again in September 2003. A further 5 million barrels were produced at high rate before commercial considerations once again forced abandonment despite the technical success.

Abandoned twice, Argyll-Ardmore was not yet dead! Ten years after cessation of production from Ardmore, the licence was once again live and EnQuest plc drilled 6 new high angle wells. What one might hesitate to call first oil was produced from the field, renamed Alma Field, in late 2015.

The aim of this paper is to examine the extraordinary development and redevelopment of the Argyll/Ardmore/Alma Field (henceforth referred to Argyll to 1992, Ardmore to 2005 and Alma to date) and determine why it was possible to redevelop the field twice.

## **Location and Discovery**

The Argyll Field occurs in a large tilted fault block in a highly elevated position on the western edge of the Central Graben of the North Sea High (Figure 1). The first well on Block 30/24 was drilled by Hamilton Brothers in 1969 and its location was based upon interpretation of sparse 2D seismic data. Indeed, 30/24-1 was plugged and abandoned before the well evaluation was complete and therefore before it was recognised to be a discovery with oil shows in the Zechstein interval. In consequence a second well 3024 was drilled close to the well 1 location. As with well 1, oil was struck in carbonate rocks at a depth of 8900 ft (TVDSS) and flowed oil at 4314 bopd from what was determined to be Permian, Zechstein dolomite. The same well also flowed 1446 bopd from a deeper sandstone reservoir, believed at the time to be the Lower Permian, Rotliegend interval but later shown to be Devonian sandstone. Appraisal followed and in June 1975 the Argyll Field became the first oil field on stream on the UK continental shelf (Pennington, 1975).

Transworld 58, a converted drilling vessel was used as the production facility. Crude oil was loaded to tanker offshore and then shipped to market. As the field came on stream, light, sweet oil flowed at high rate. Drilling continued to add ever more production wells to the portfolio and although each new well was drilled deep into the red-beds beneath the Zechstein interval only the Zechstein vuggy and fractured carbonates was ever completed for production. Deeper oil was often proven and flow tested as well as pressure measurements taken but wells were effectively plugged beneath the Zechstein. It was about four years after production start up, in mid-1979 that a well was completed in the sandstone interval beneath the Zechstein. Hamilton Brothers Oil Company kept very detailed records on the drilling and

completion of wells but we have not found any information which allows us to understand why the company only developed one formation per well and the temporal progression was from completion of the youngest, shallowest Zechstein reservoir early in the production history to deeper and older reservoirs late in field life.

These deeper, oil bearing sandstones though described as Rotliegend were for the most part, unlike those seen in the Southern North Sea Gas Basin and onshore England. Eventually, the sandstones were recognised to be a combination of Permian Rotliegend sandstones and Devonian (Old Red) sandstones and siltstones (Heward *et al*, 2003).

Small amounts of oil were found in shallow marine Upper Jurassic sandstones that only occur on the western flank of the field (30/24-6 and 30/28-8). More surprises were discovered. In the north east of the field the Zechstein reservoir is completely eroded and Upper Cretaceous Chalk seals variably fractured but otherwise tight Devonian sandstones that were proven productive by well 30/25a-2 (1982, tested at 2280bopd) but never completed as a producer. The seal horizon within this well is within the Chalk, the lower part of which is oil bearing. Core from 30/24-20 (1982) revealed a conglomerate facies of Upper Jurassic age containing pebbles of Zechstein dolomite and oil bearing matrix which had not been described previously. Even the final well drilled by Hamilton on the southern edge of the field (30/24-39, 1989) delivered a further puzzle when volcanic rock (probably lowermost Permian Karl Formation, Stemmerik *et al*, 2000)) was encountered at the level where Rotliegend sandstones were expected.

Production peaked in 1976 only one year after the field began production (Figure 2) with a half year average of about 28,000bopd. At this time only the Zechstein interval was on production. Wells completed in the Rotliegend were added in 1979 and the Devonian was

brought on stream in 1982. This gave two lesser peaks in production of just over 20,000bopd in the first halves of 1979 and 1982.

Two smaller discoveries in the block were later tied back to Argyll (Duncan, Jurassic reservoir, 1984; Innes Rotliegend reservoir, 1985). The Innes crude has a higher gas-oil ratio than that of Argyll and its excess gas production was used for gas lifting the Argyll wells. Despite the addition of gas lift, oil production from all three fields continued to fall and by 1992 the daily rate was 6000 bopd. This combined with 14,000 barrels of water production to give a total fluid production of 20,000 barrels per day. A changed production set up several years previously meant that the total fluid capacity of the vessel was 20,000 barrels per day. Despite their being tested but unproduced wells the combination of vessels throughput capacity and insufficient gas for gas lifting all wells served to limit oil production to 6000 bopd and falling. In the absence of a larger vessel capable of handling more fluids, the field was failing. Hamilton Brothers were in the process of being taken over by BHP and oil was below \$20 per barrel. A cessation of production document was lodged with the Department of Trade and Industry and the Argyll Field along with Duncan and Innes fields were abandoned.

## Structure, and Stratigraphy

The Argyll Field is at the southern end of the Central Graben. It lies largely on the rift shoulder straddling the major bounding fault to the southernmost part of the Central Graben and above a significant transfer zone. Movement within this zone caused repeated inversions of the fault block that contains Argyll and this led to the complex, residual stratigraphy seen in the area with multiple and composite unconformities. The most recent inversion appears to have occurred in the early Neogene, giving Argyll its characteristic elongate NE-SW trap geometry (Figure 3).

The key stratigraphic sections are:

### *Devonian*

The oldest rocks penetrated in Argyll are Devonian, Kyle Group limestones, formed during widespread marine transgression in Middle Devonian age (Ziegler, 1990) and informally referred to as the 'Mid Devonian Limestone', a conspicuous, high-amplitude and continuous seismic reflector for recognizing Middle Devonian strata (Milton-Worsell *et al*, 2010). The reservoir interval in Argyll is the Buchan Formation of the Upper Old Red Group, a thick succession of continental red-beds that overlie the limestone. Deposition of the sandstone dominated Devonian interval occurred in both fluvial and aeolian environments.

The Devonian dips at 7-10° to the SW with the oldest rock in the NE corner of the Argyll Field (30/25a-2). Progressively younger Devonian subcrops the base Permian Unconformity to the SW (Figures 4 and 5). The Devonian section may contain subtle angular unconformities as well as having considerable missing section although unequivocal



evidence of such is lacking. In the early well and field reports, what we now know to be Devonian strata were referred to as Rotliegend Gamma.

*Permian – Rotliegend & Zechstein (Figure 6)*

Overlying what is confidently identified as Devonian sandstone in well 30/24-10 in the north of the field is a rock described as weathered olivine basalt beneath 30m of white sandstone. In the southwest of the field, 30/24-39 includes weathered volcanics or volcaniclastics beneath the Zechstein carbonates. Both intervals may be lowermost Permian Karl Formation.

Argyll lies within the area known as the Northern Permian Basin and Early Permian, Rotliegend, Auk Formation sandstone overlies the Devonian. This interval was originally referred to as Rotliegend Alpha to distinguish it from what we now know to be Devonian strata and which in the early days was called Rotliegend Gamma. No references have been found to a Rotliegend Beta in the drilling or completion reports or indeed the early field appraisals. It is possible that such a term was reserved for a unit that might be seen between the clearly discordant Gamma and Alpha intervals. Rotliegend sandstones *sensu stricto* in Argyll are confined to a low relief northwest-southeast syn-depositional valley through the centre of the field (Robson, 1991). These sandstones are typical Rotliegend aeolian and non-fluvial, waterlain facies, redeposited by rainfall on the dune surface. Beyond the immediate area of the Argyll Field, the Rotliegend sandstones are widespread and thicker with a greater range of facies (including fluvial sandstones; Heward *et al*, 2003).

The Kupferschiefer mudstone and Zechstein carbonates overstep the Rotliegend sandstones and rest directly upon the Devonian strata (Figure 6). The Kupferschiefer mudstone is not everywhere present and it is possible that it was not deposited over the crest of the partially collapsed Rotliegend sand dunes ahead of the Upper Permian, Zechstein marine incursion. Halibut Bank Formation carbonates overlie the Kupferschiefer and are in turn overlain by the Sapropelic Dolomite and Turbot Bank Formation carbonates.

The original fabric of the Halibut and Turbot formations is difficult to determine due to pervasive dolomitisation, dedolomitisation and brecciation. The Halibut Bank interval has a transitional boundary with the Kupferschiefer. It comprises friable and argillaceous dolomite interlaminated on a centimetre scale with non-porous dolomite. This is overlain by an upward coarsening, poorly sorted, clast supported dolomite breccia.

The Halibut Bank Formation passes transitionally upwards into the basal unit of Turbot Bank Formation (Sapropelic Dolomite). It is a laminated dolomitic argillaceous mudstone with very thin (mm-scale) graded dolomitised beds.

The Turbot Bank Formation passes transitionally upwards from the laminated carbonate slope facies at the top of the Sapropelic Dolomite into a meso- to finely crystalline dolomite with possible biomoulds.

Deposition of the carbonate intervals occurred in a shallow marine environment around what was an intrabasinal high, the embryonic Argyll structure. The carbonates overstep Rotliegend sandstones and over much of the field area rest directly on eroded Devonian

sandstone. From time to time the water column became anoxic leading to deposition of the sapropelic units. The Zechstein succession at Argyll contains no anhydrite and no halite in contrast to elsewhere in the Northern Permian Basin. The presence of collapse breccias at Argyll is taken to indicate that some evaporate minerals may well have been dissolved but it is also likely that the structurally elevated position of the Argyll area in the Late Permian limited evaporite deposition through lack of accommodation space.

#### *Upper Jurassic Humber Group*

The best development of Upper Jurassic Fulmar sandstones occurs in a north to south strip, across the centre of the field. Here it only poorly developed as a combination of basal breccia with pebbles of Zechstein dolomite overlain by clean quartzose sandstone. On the western flank of Argyll the shallow marine, Fulmar sandstone is better developed. Well 30/24-6 produced about a 0.4 million barrels of oil from this interval.

#### *Upper Cretaceous – Palaeocene Chalk Group*

The Chalk is present across the whole of Quad 30 indicating that by Upper Cretaceous times the area was finally submerged. Oil shows occur within this interval across Argyll although the same stratum is the ultimate top seal in the north-eastern corner of the field.

#### *Palaeocene/Eocene – Recent Stronsay, Westray and Nordland Groups*

The Tertiary section that overlies Argyll is largely argillaceous and it is not considered to be prospective.

## Reservoirs

Argyll contains four reservoir units (Devonian, Rotliegend, Zechstein and Late Jurassic, Figure 6). The three oldest are in pressure and fluid communication and the fourth, youngest and minor unit (Jurassic) is independent (Figure 6).

### *Upper Devonian*

The oil bearing section of the Buchan Formation contains sandstones and siltstones with subordinate mudstones, conglomerates and rare carbonaceous mudstones; these only occurring in the very youngest part of the Buchan Formation. The log trends and core exhibit a cyclicity of sandstone and finer sediments for the whole of the interval but there is also a clear overall upward trend to cleaner better sorted sandstones interbedded with mudstones from a rather homogenous and monotonous collection of silty sandstones and sandy siltstones at the base. The Buchan Formation has been divided into intervals interpreted to have been deposited in either arid or semi-arid environments and then wells are correlated using the wet-dry cyclicity.

The ranges in porosity and permeability for the sandstones within the Devonian section are large, from 5-28% and <1mD to >1D respectively (porosity arithmetic mean 14.4%, permeability arithmetic mean 340mD, permeability geometric mean 10.5mD).

One of the more intriguing aspects of the Devonian reservoir interval is the heterogeneity and anisotropy of its reservoir quality. Most noticeable in slabbed core, is the distribution of oil stained and non-oil stained rock. Only about 30% of the rock is oil stained, while in excess of 80% is sandstone with much of the remainder being siltstone and only a few mudstones

towards the top of the Devonian (SW of field). The non-oil stained sandstones are thoroughly cemented (Tang *et al*, 2016). In addition there is a progressive diminution in oil saturation with depth/stratigraphy in wells that penetrate the Devonian section. The causes of cementation/non-cementation and their impact on reservoir performance are the topic of current research (Tang *et al*, 2016).

### *Rotliegend*

The Rotliegend in Argyll reservoir consists of different proportions of four main facies associations. These infill end-Carboniferous topography and onlap the Argyll High (Heward *et al*, 2003). The four facies associations include:

- Aeolian Slipface Sandstones
- Aeolian Ripple-laminated Sandstones
- Waterlain Sandstones
- Waterlain Conglomerates and Breccias

The most permeable facies within the Rotliegend are the coarse waterlain sandstones (Weissliegend) that dominate Unit 1. The most porous reservoirs are the medium grained dune slipface sandstones, most abundant in Unit 3. Units 2 and 4, dominated by wind ripple-laminated sands, have low permeability and have characteristically high water saturations. Permeability in the waterlain sandstones of Unit 1 and aeolian sandstones is high, typically 1-5D.

Production logs run during the completion of Argyll wells 30/24-11 and Innes well 30/24-24 (15km north of Argyll) confirm that the bulk of production was from Unit 1. Seven wells

produced oil from the Rotliegend reservoir in Argyll. However, material balance estimates indicate that the Auk Formation was not just an oil producer. It alone amongst the reservoirs of Argyll has a substantial aquifer. Aquifer size has been calculated to be about 10 billion barrels based both upon the material balance calculations and also from pressure data gathered from exploration wells drilled to the north and west of Argyll after production began (Heward *et al*, 2003).

### *Zechstein*

The Zechstein interval contains dolomite and subordinate limestone. The dolomite replaces calcite and much of the original fabric of the limestone has been lost. The Zechstein reservoir comprises a dual porosity system of large pores easily visible to the naked eye and micropores detected during core analysis. The large scale macro pores visible in core comprise fractures and vugs. Some of the fractures are of tectonic origin are, but most comprises anastomosing fracture systems within collapse breccias. Vugs include irregular 100µm to 5mm diameter pores formed by dissolution of allochems during dolomitisation and evaporite dissolution. Some vugs are also formed by non-fabric selective dissolution.

Core plug measurements from the Zechstein reservoir are few because much of the core is fragmented. In consequence the measured poroperm data are be biased towards the poorer quality reservoir. The highest porosities have been measured in the collapse breccias that have both intercrystalline and vuggy porosity (porosities of up to 20% and permeability up to 1D). Porosity and permeability are poorly correlated. Indeed many plugs have only about 5% porosity while permeability values measured in hundreds of millidarcies have been

recorded. The cause of the high permeability at low porosity is fracturing. This appears to be natural and not core induced.

Given the difficulty of quantifying the reservoir quality of the Zechstein from the existing conventional core analysis data, additional information has been taken from the drilling reports. Mud losses were common during drilling of the karstic layers in both the Turbot and Halibut Formations with reported rates ranging from 60-200 barrels per minute. The effects of this mud invasion are readily seen in both fractures and vugs within the core. Drilling of the Zechstein was also typified by erratic drilling breaks and frequent jamming of the core barrel.

#### *Upper Jurassic*

The Upper Jurassic Fulmar Formation reservoir is poorly developed on the west flank of Ardmore where it comprises fine to medium grained clean to argillaceous sandstones. Net to gross is typically high (80-100%) and porosity in the range 16-21%. Permeability varies widely from a few millidarcies in the more argillaceous intervals to a few hundred millidarcies in the cleanest sandstones. The Jurassic of Argyll was not cored although that of the immediately adjacent Duncan Field (now called Galia) was cored. Here the Upper Jurassic Fulmar sandstone is interpreted to have been deposited as offshore bar sandstones into which sand-filled tidal channels are cut. Other wells in the 30/24 Block to the north of Argyll often have very poor sandstone development while a further sand bar complex forms the oil accumulation informally called Iris in Block 30/29 to the south of Argyll.

## **Source**

The Upper Jurassic Kimmeridge Clay Formation is the source rock for oil within each of the three fields on Block 30/24. The kitchen area was the deep Central Graben to the east and north of Argyll and the likely sourcing direction from the north along a broad ramp linking Argyll (and Duncan) with Innes to the north. There may have been several phases of petroleum migration as evidenced by the distribution of a fluorescent dead oil and non-fluorescent live oil in Innes and two oil types recorded from the Affleck Field to the north of 30/24. Given we know the Rotliegend to be the main aquifer in the region it is reasonable to assume that oil migration occurred through this interval too. Filling of Argyll was likely via the saddle which separates its western flank from the Duncan field. On entering the Argyll structure the Devonian section was filled downwards and Zechstein section upwards from the Rotliegend.

## **STOIIP & Reserves**

Initial oil in place and reserves has been calculated many times for Ardmore and its predecessor Argyll since the field was discovered in 1969. Nine sets of STOIIP calculations from internal company records between 1982 and 2003 have been collated. These range from 185 to 375 MMstb for the four reservoirs combined (Table 1). A significant uncertainty affecting gross rock volume is the depth of the initial oil water contact. There are few penetrations of a proper contact with the most common value being around 9360ft TVDSS as seen in the central and southwestern parts of the field. Projection of a deeper contact (9430ft TVDSS) on a field wide basis certainly accounts for most of the additional oil in the highest STOIIP figure, with most increase occurring in the Devonian reservoir. In the north eastern



part of the field the quality of the Devonian reservoir diminishes and, in most instances only  
'oil down to' depths that have been measured.

The P<sub>50</sub> STOIP estimate is 375 MMstb (summed means). The subdivision by reservoir  
gives 33 MMstb in the Jurassic, 42 MMstb in the Zechstein, 50 MMstb in the Rotliegend and  
250 MMstbl in the Devonian.

It is interesting to note that the STOIP figure used by Hamilton Brothers Oil Company  
cessation of production report is the lowest of all STOIP figures found while the figure used  
by Tuscan and Acorn prior to redevelopment of the field as Ardmore is the highest. It is  
difficult not to think that some influence was brought to bear on the technical evaluation by  
the circumstances of the two sets of companies; one wishing to abandon the field and the  
other to redevelop the field.

#### Argyll Production

The Argyll Field produced 72.6 MMstb with 41.1 MMstb from the Zechstein reservoir,  
18.2 MMstb from the Rotliegend reservoir and 12.8 MMstb from the Devonian reservoir.

The Fulmar sandstone produced about 0.4 MMstb from one well. Comparison of STOIP  
and produced reserves appears to indicate that recovery factor for the Zechstein was almost  
100% and about 37% for the Rotliegend while only 5% of the in place volume of Devonian  
oil recovered. Clearly the recovery factor for the Zechstein is unreasonable. It is known  
from the pressure data that the Zechstein, Rotliegend and Devonian reservoirs are in  
communication and therefore it is concluded that some of the oil produced from the  
Zechstein was originally reservoired in either the Rotliegend or Devonian. Analysis of the  
well performance of those wells completed in the Zechstein reveals a correlation between the

volume of oil produced before water breakthrough (measured at a water oil ratio of 0.5) and the lateral distance to the nearest known aquifer. For early wells the nearest known aquifer was the field margin while for later wells it was taken to be any well cutting substantial water (Figure 7). This simple linear relationship is in contrast to the complex reservoir geology in the Zechstein and it is taken to indicate that the principle transmissive component of the Zechstein reservoir is the pervasive fracture system and moreover that this trend is observable in the absence of any bottom water to the field.

The remaining reserves for the second phase of development of the field when it was named Ardmore, were calculated both by extrapolating the water-cut trend for the Ardmore Field and by modelling the reservoir using material balance. Both methods give similar results. When Argyll was abandoned it was producing about 6000 bopd. The total daily fluid rate was 20,000 bfpd, a figure constrained by the production facility then available. Thus at abandonment the water oil ratio was about two and extrapolation of the water oil ratio to five (Figure 8) yields a remaining oil reserve of about 25 MMstb (range 20 – 40 MMstb).

### **Ardmore Development and Production**

For the Ardmore development, three firm and one contingent well were planned for the first phase of field redevelopment to access the remaining 25MMstb of oil reserves. A further three sub-surface locations were identified as possible future well locations dependent upon the outcome of initial drilling and production (Figure 9). The limited finances available for the Ardmore project led to sub-optimal redevelopment of the field. No funding was available to drill water injection wells, nor pay for top-sides injection facilities. The contracts for the first three wells were turn-key. This then allowed the drilling contractor to define the well

geometries and limit angle through the reservoir section to 60°. The funding model also demanded rapid payback and hence wells had to be completed in the highly productive Zechstein interval from day 1, where as a recovery mechanism optimised to maximising recovery would have begun with completion of the lower rate and deeper Devonian intervals (see below). By the time the field was abandoned for a second time three new wells had been drilled and two of these new wells had been sidetracked.

Two types of target were identified for the Ardmore wells. The low risk targets are Devonian reservoired oil, proven during the Argyll phase but never produced. The reservoir quality is variable from poor to good and well rates were expected to be modest relative to the rate that could be achieved from Rotliegend and Zechstein completions. The most likely initial water cut in such wells was calculated to be zero.

The higher risk targets were Zechstein and Rotliegend reservoirs where because of their excellent properties unconstrained well rates could exceed 20,000 bopd. The prediction of the initial water cut in such wells and the rate at which water cut would increase was the major risk. Oil production from Ardmore was not as expected, although it took some while to understand that it was not errors in the reservoir description but rather failure to execute drilling and completions as planned. This was compounded by problems with the production facility that was unable to meet the design criterion and handle 50,000bwpd.

The first well drilled for the Ardmore production phase (30/24-T1, ARD-A) was located updip of one of the best wells from the Argyll production period (30/24-9). Tuscan and Acorn had the benefit of being able to place the well on the basis of interpreted 3D seismic

data while only a sparse 2D data set was available to Hamilton. T1 was expected to penetrate Zechstein carbonates lying above Devonian sandstones. It was anticipated that flushed horizons could occur anywhere in the section. On the basis of the old wells it was thought probable that the base of the Zechstein or top of the Devonian were likely to be flushed as this interval was coincident with the top perforations in the old well nearby.

Given the limited funds available to the two companies, it was deemed necessary to produce the well at the highest rate possible, that is, from the combined Zechstein and Devonian. It was recognised that water ingress to the Zechstein was likely to be rapid and to this end a different, less simple, completion strategy was employed. A sliding sleeve was used as part of the completion over the Zechstein interval. The idea was that water could be shut off from Zechstein leaving only the Devonian producing.

Well 30/24-T1 was drilled in August 2003. Petrophysical analysis revealed a full oil column. No water was encountered. The Zechstein was high quality as was the underlying uppermost Devonian. Pressure data indicated that in 11 years the field had recovered about two thirds of the way between the virgin pressure and the field abandonment pressure. All looked good.

In October 2003 production began. The choke was progressively opened and under natural flow the rate increased to over 20,000bopd – miracle. The rate was about 30% higher than any previous well had ever managed during the Argyll production phase. A production rate in excess of 20,000bopd was maintained for two months without resort to switching on the electro-submersible pump. During these two months a second well T2 (ARD B) was drilled in the mid-part of the field. Petrophysical analysis of this well indicated that some intervals

in both the Zechstein and the very thin Rotliegend sections encountered were water flushed and in line with prognosis an initial water oil ratio of about one was anticipated. Preparation was made to bring T2 on stream. However, in the days just before T2 can on, BS&W (base solids and water) in T1 began to rise from near zero to a few percent. Clearly water breakthrough had begun to occur. T2 came on stream and despite a 50% water cut the field production rose to 28,000bopd; just for one day. Then the unexpected happened. Although the production equipment had been designed to handle 50,000bwpd it could not handle a total fluid of 20,000bpd – disaster. Day after day the water oil ratio increased and day after day the production system tripped. Efforts to reduce the water cut by closing the sliding sleeve failed. Could water be flowing through the Devonian at such high rate?

Two problems with the production facility were eventually identified and remedial work begun to correct the equipment which had not been built to specification. However, it took about six months before the production system could handle the 50,000bwpd as designed and an enormous quantity of oil production and hence revenue had been lost.

The problem with T1 remained and as water cut increased so oil production decreased. By mid-2004 the field was producing only 1500bopd and at that rate it was failing to return sufficient revenue to pay of the loans made to the two companies. Problems with the flow multimeter also meant that it was not possible to be confident about the relative proportions of oil and water production from the two wells. Meantime T3 (ARD C) was being drilled.

Eventually the decision was made to work over T1 and try to shut off the water. In doing so the source of the water was revealed. It was coming from the Zechstein but an error in

placing the sliding sleeve meant that even when the sleeve was in the closed position it was not covering the perforated interval (Figure 10). Moreover, it was also discovered that the Devonian section was completely filled with lost circulation material. It had not produced a barrel of oil. The Devonian interval was cleaned and the Zechstein section blanked-off. When the well was brought back into production it flowed at 11,000bopd from the Devonian alone; a rate three times better than had ever been seen from the Devonian during the Argyll production period – miracle.

Had well 30/24-T1 been drilled and completed correctly the well would have produced over 30,000bopd and history would have been different. However, the damage was done and despite a further well and two sidetracks being drilled the field was little more than breaking even. The two companies had insufficient funds to drill their way out of the problem. By mid 2005 Tuscan ceased trading, leaving Acorn to limp on. Acorn did raise sufficient funds to continue, but in an environment of rapidly rising oil price and consequential hike in day-rates for contractors, contracts were terminated. Acorn oversaw that abandonment of the three wells and closed the second chapter in the Argyll/Ardmore production history. Ardmore produced an additional 5 million barrels.

## **Discussion and Conclusions**

Two small companies with very limited resources brought the abandoned Argyll Field back to life as the Ardmore Field. First oil was achieved in less than two years from acquisition of the licence. The limited resources meant that there was no margin for error with the development. However, there were errors and despite those being small relative to many

other field start-ups, the two small companies were unable to continue to produce the field.

Ardmore was not a commercial success although the production proved beyond doubt that there are about 20mm bbl remaining which for a properly capitalised company should make an attractive development.

It is interesting to compare the development schemes of Hamilton for Argyll and Tuscan/Acorn for Ardmore.

Argyll was developed from a floating facility with very limited options for well intervention. The field development relied upon depletion drive and limited natural aquifer inflow. All wells were vertical or nearly so. Gas lift was used to maintain flow as pressure declined. A change-out of production vessel limited the production capacity as water cut increased and there was insufficient gas to lift all wells with proven and flowed oil. Ultimately the first life of Argyll was geared towards Hamilton beating BP to first oil from the North Sea and demonstrating high rate production albeit for a short time.

Ardmore was developed from a fixed platform, with technical options for interventions but low funds to execute any interventions. The field development relied upon depletion drive and limited natural aquifer inflow. All wells were drilled as inclined. Initially wells were allowed to flow naturally and subsequently electro-submersible pumps used to maintain flow. Drilling and production execution errors limited oil production and hence income. This in turn brought a premature end to production from Ardmore. On reflection though the Ardmore phase of development basically used the same strategy as the Argyll phase of development, produce as much oil as possible as fast as possible.

## Postscript

In December 2010 the area containing what had been the Argyll and then the Ardmore Field was relicensed; this time to a far more financially robust company, EnQuest plc. Their plans for a second redevelopment of the Ardmore Field contain, for the first time, water injection and pressure support. Production recommenced in October 2015 and the latest production figures released by EnQuest are for April 2016 with Alma and Galia (formally Duncan) combined production above 9000 bopd.

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## Figure Captions

Fig. 1 Regional Position of the Ardmore Field showing the Tuscan/Acorn licensed Blocks (structure adapted from Gluyas *et al*, 2005)

Fig. 2 Production profile for the Zechstein, Rotliegend, Devonian and Jurassic reservoirs of the Argyll Field from start-up in 1975 to abandonment in 1992.

Fig. 3 Top Reservoir Depth Structure map of the Ardmore Field showing the original Argyll Field well locations

Fig. 4 SW-NE depth cross section across the Ardmore Field showing the stratigraphic relationships of the productive Jurassic, Zechstein, Rotliegend and Devonian reservoirs above a nominal IOWC of 9360 ft TVDss

Fig. 5 NW-SE depth cross section across the Ardmore Field showing the stratigraphic relationships of the productive Jurassic, Zechstein, Rotliegend and Devonian reservoirs above a nominal IOWC of 9630 ft TVDss

Fig. 6 General stratigraphy of the Ardmore area.

Fig. 7 Relationship between water breakthrough oil volumes and date versus lateral distance to aquifer.

Fig. 8 Water-Oil ratio and cumulative oil production plot for the Argyll Field. Projection of the water cut to a water oil ratio of about 9:1 would deliver an additional 25mmbbl in the Ardmore redevelopment.

Fig. 9 Possible new well trajectories for the Ardmore Field development.

Fig. 10 Relationship between perforated liner in T1 and sliding sleeve arrangement.

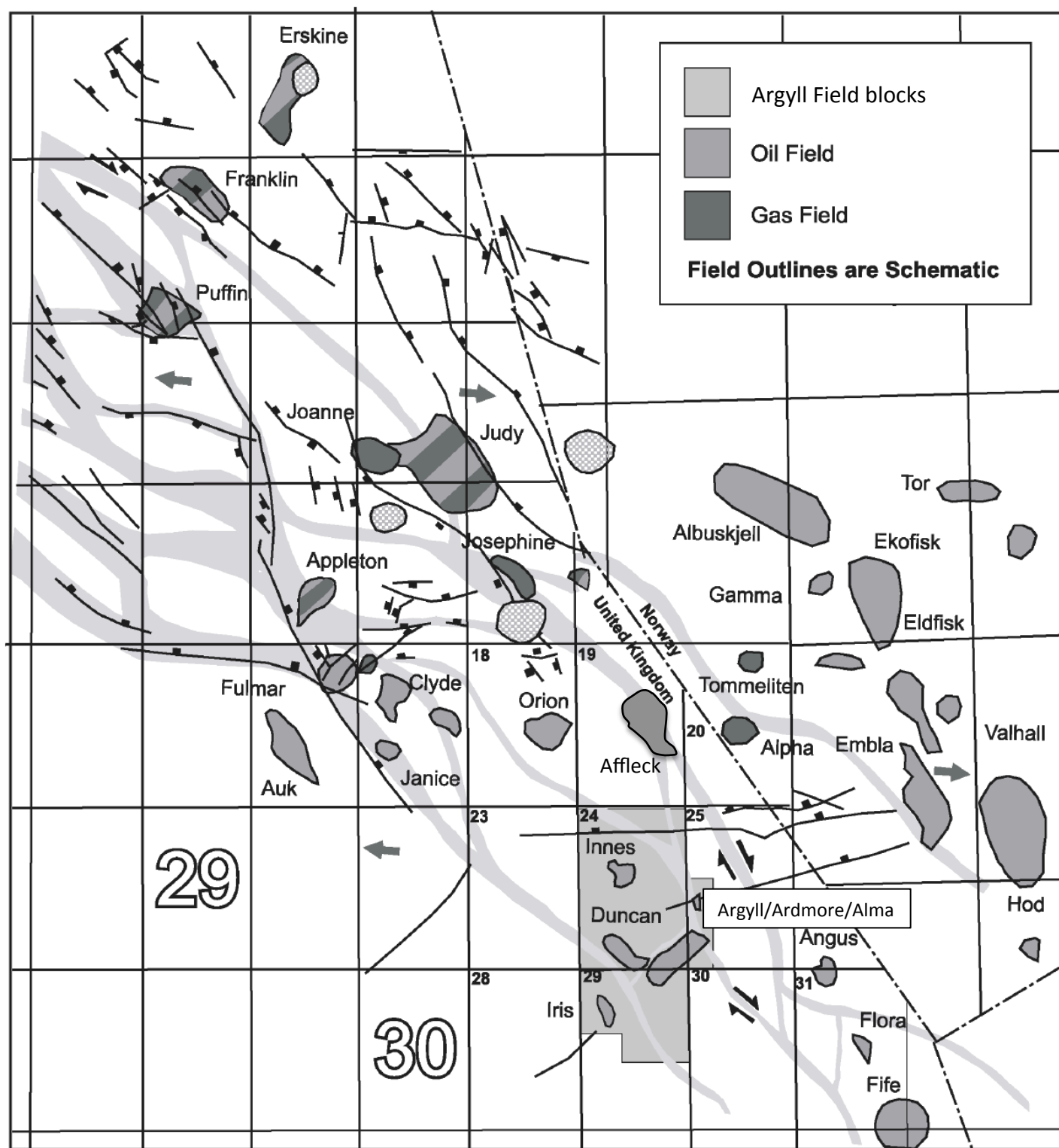
Table 1 Original Oil in Place calculations by different field owners

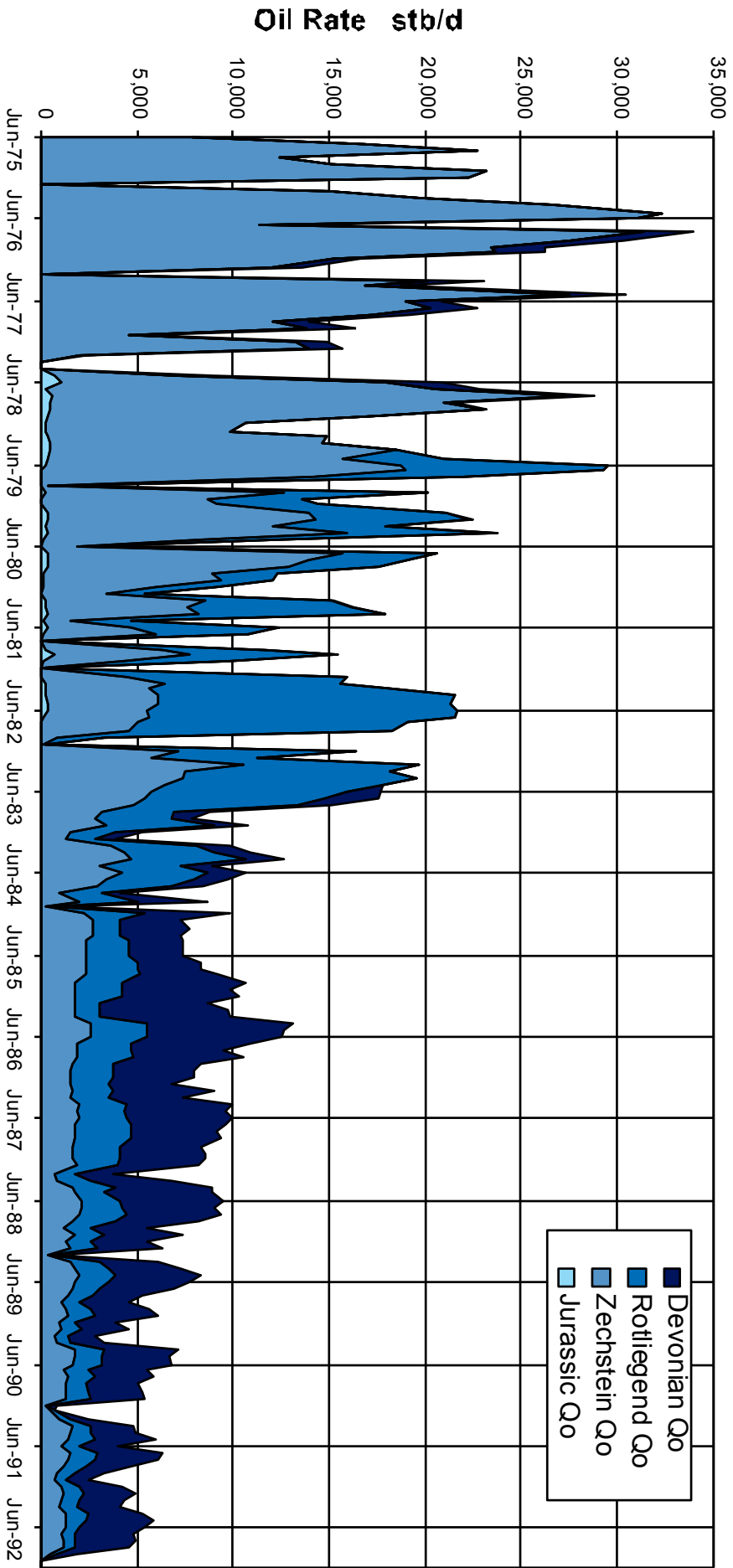
Reporting entity	Year	Mean or P50 STOIIP (mmstb)	Notes
Hamilton Brothers Oil Company	Jan 1982	342	Although the field was on stream by June 1975, these are the earliest STOIIP figures found
Hamilton Brothers Oil Company	Feb 1984	266	Notes from Technical Committee Meeting
ERC	Jul 1986	218	Technical consultant report
Hamilton Brothers Oil Company	Apr 1989	225	Reservoir re-evaluation report
Hamilton Brothers Oil Company	Jul 1991	198	Cessation of production report
Blackwatch	Sept 1997	277	Consultant report for Monument Oil & Gas
Atlantis	Jan 1998	202	Would be redevelopment company
Lasmo	Dec 2000	185	Consultant report for Lasmo
Tuscan & Acorn	From 2001	375	One of several STOIIP figures generated by Tuscan and Acorn. This one used in the redevelopment plan

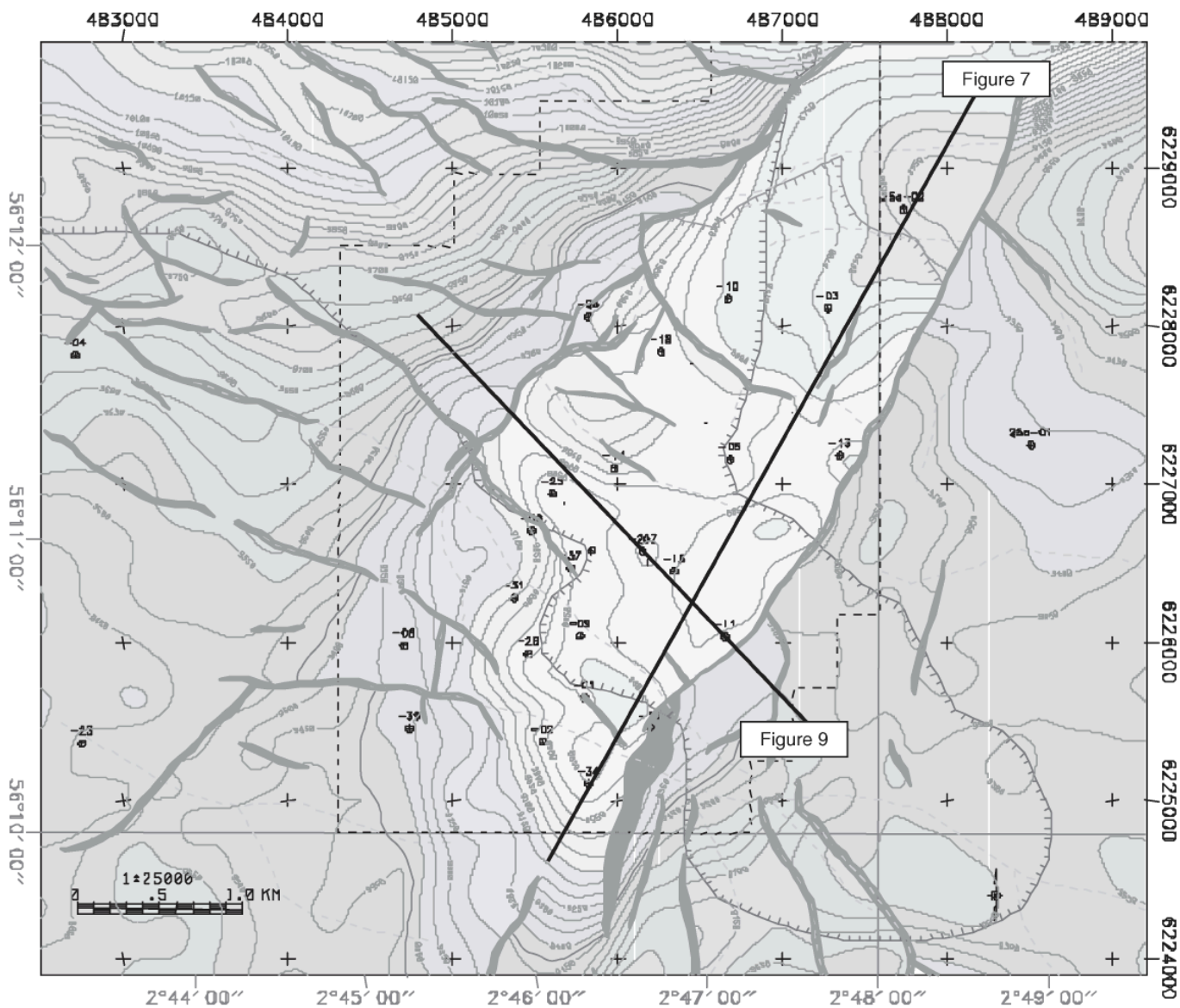
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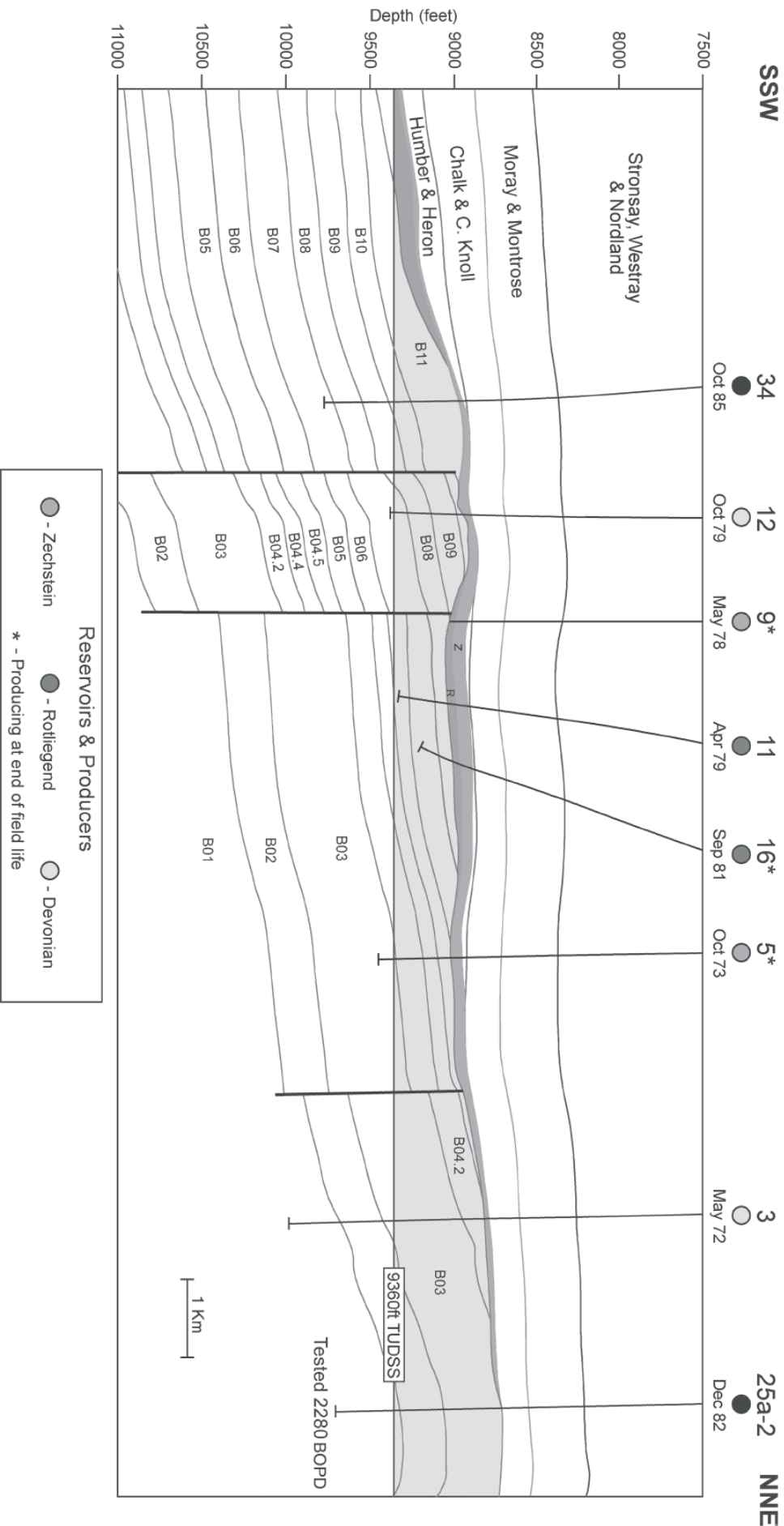
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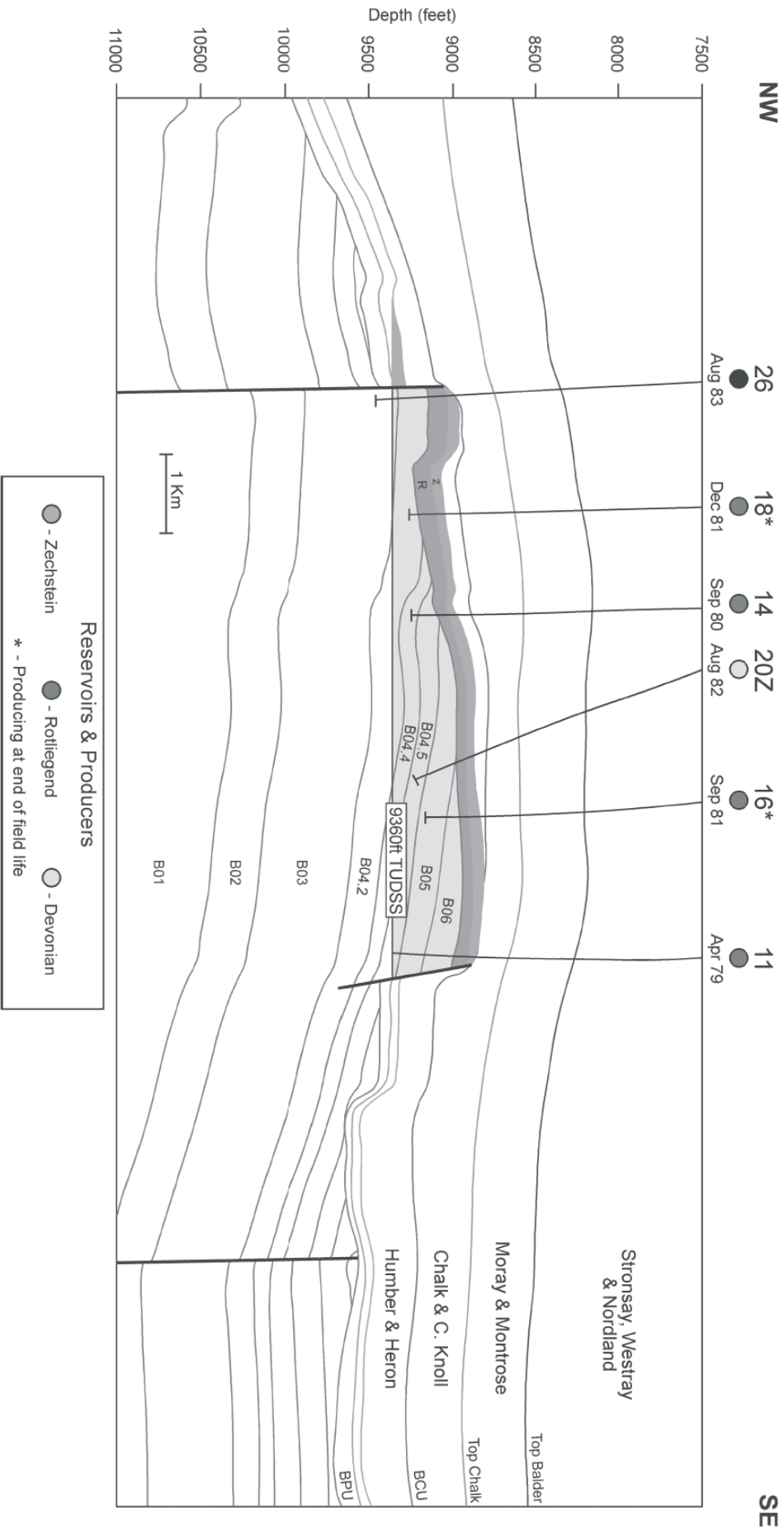






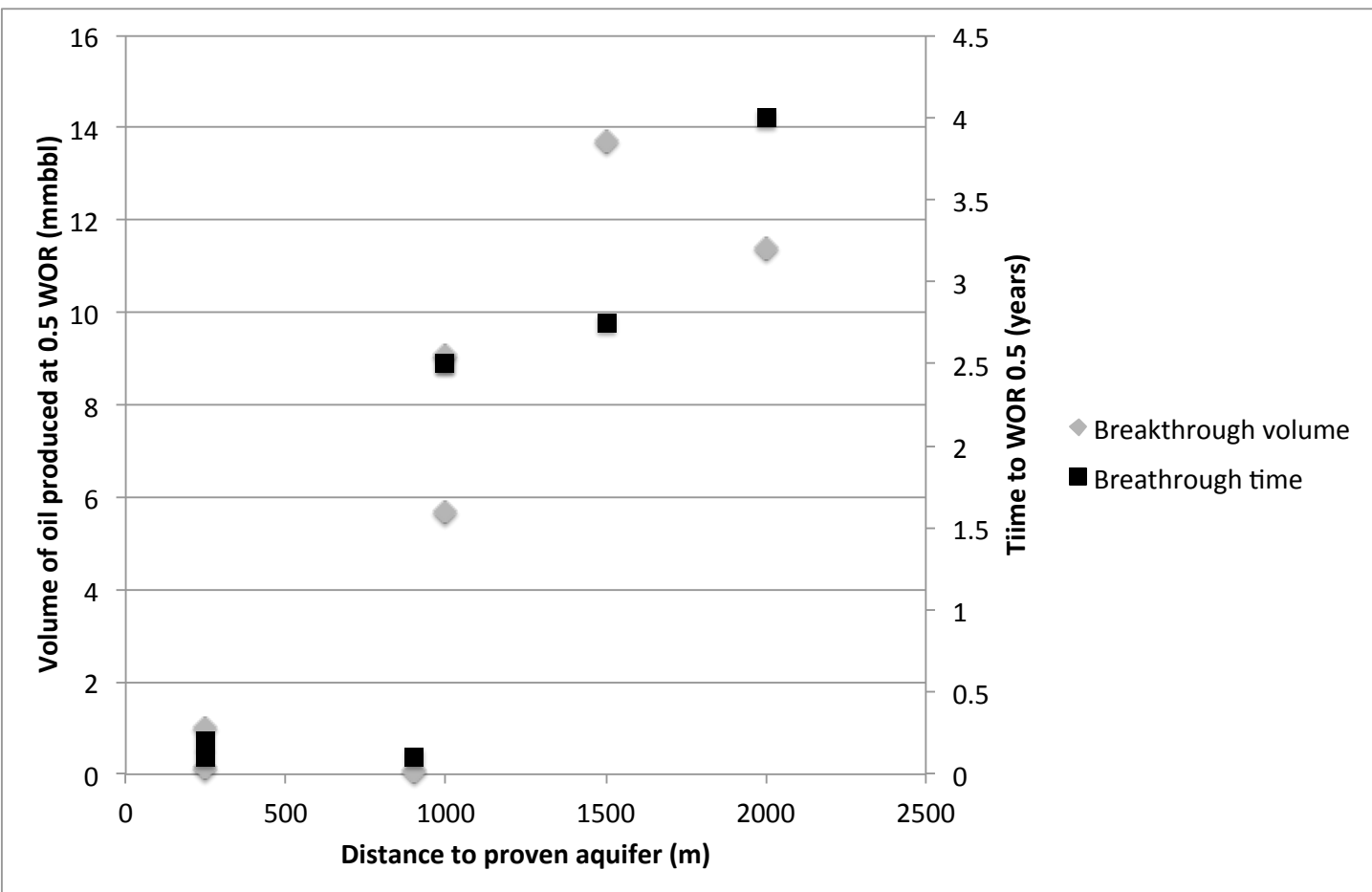
 RotliendSubcrop 
  BCUTruncation 
  CrossSections 
  LicenceBoundary 
  OWC 9430'TVDSS

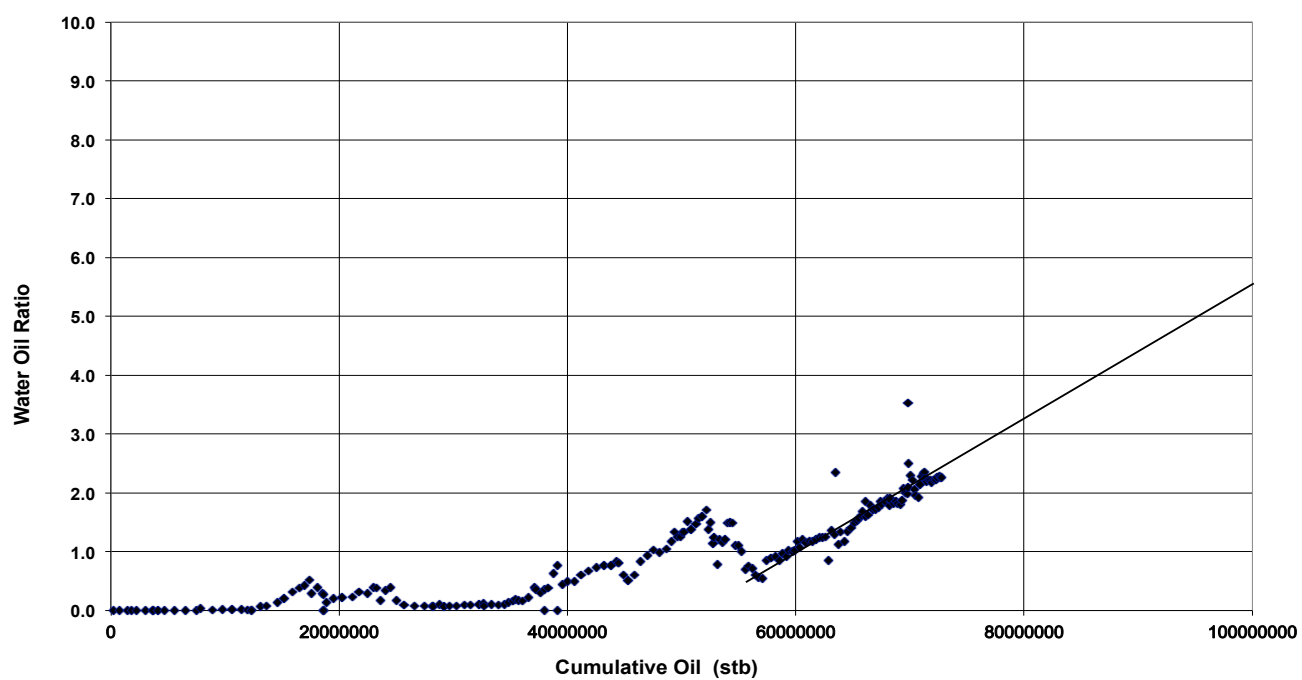


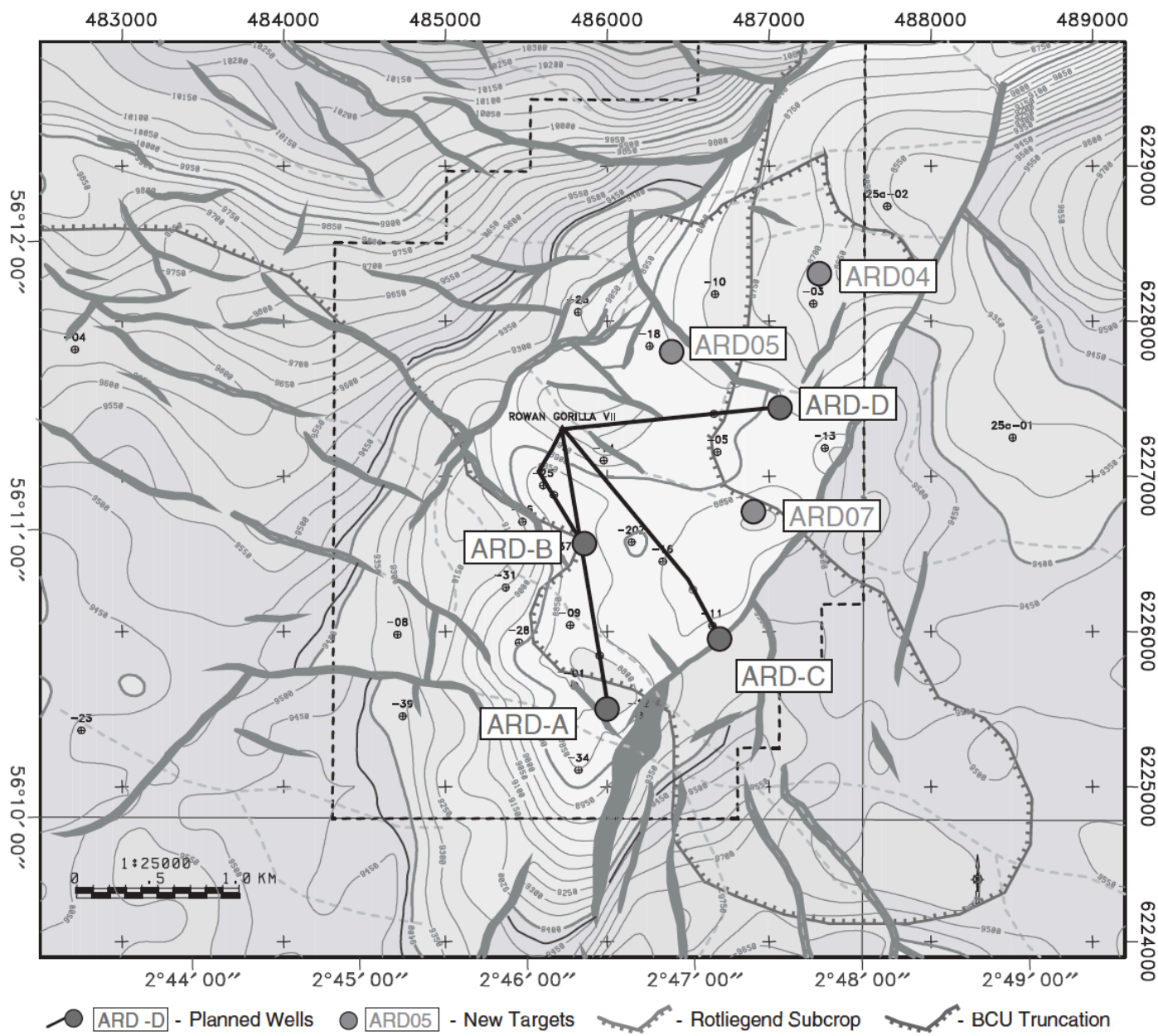




STAGE	GROUP	FORMATION	MISSING SECTION	SEISMIC EVENTS
Recent-Early Miocene	NORLAND	Undiff		
Oligocene	WESTRAY	Skade/Lark		
Late Eocene	STRONSAY	Mousa		
Early Eocene				
Paleocene	MORAY	Balder		Top Balder
		Sele		
	MONTROSE	Lista		
		Maureen		
		Ekofisk		Top Chalk
Late Cretaceous	CHALK	Tor		
Early Cretaceous	CROMER KNOLL	Valhall		Base Cretaceous Unconformity
Late Jurassic	HUMBER	Kimmeridge Clay		
		Fulmar		
Early Jurassic	FLADEN			
Triassic	HERON	Smith Bank		
Late Permian	ZECHSTEIN	Turbot		
		Sapropelic Dolomite		
		Halibut		
		Kupferschiefer		Base Zechstein
	ROTLIEGEND	Auk		
Early Permian	KYLE	Karl		
Carboniferous ?				
Devonian	UPPER OLD RED SANDSTONE	Buchan		
				Mid Devonian Limestone







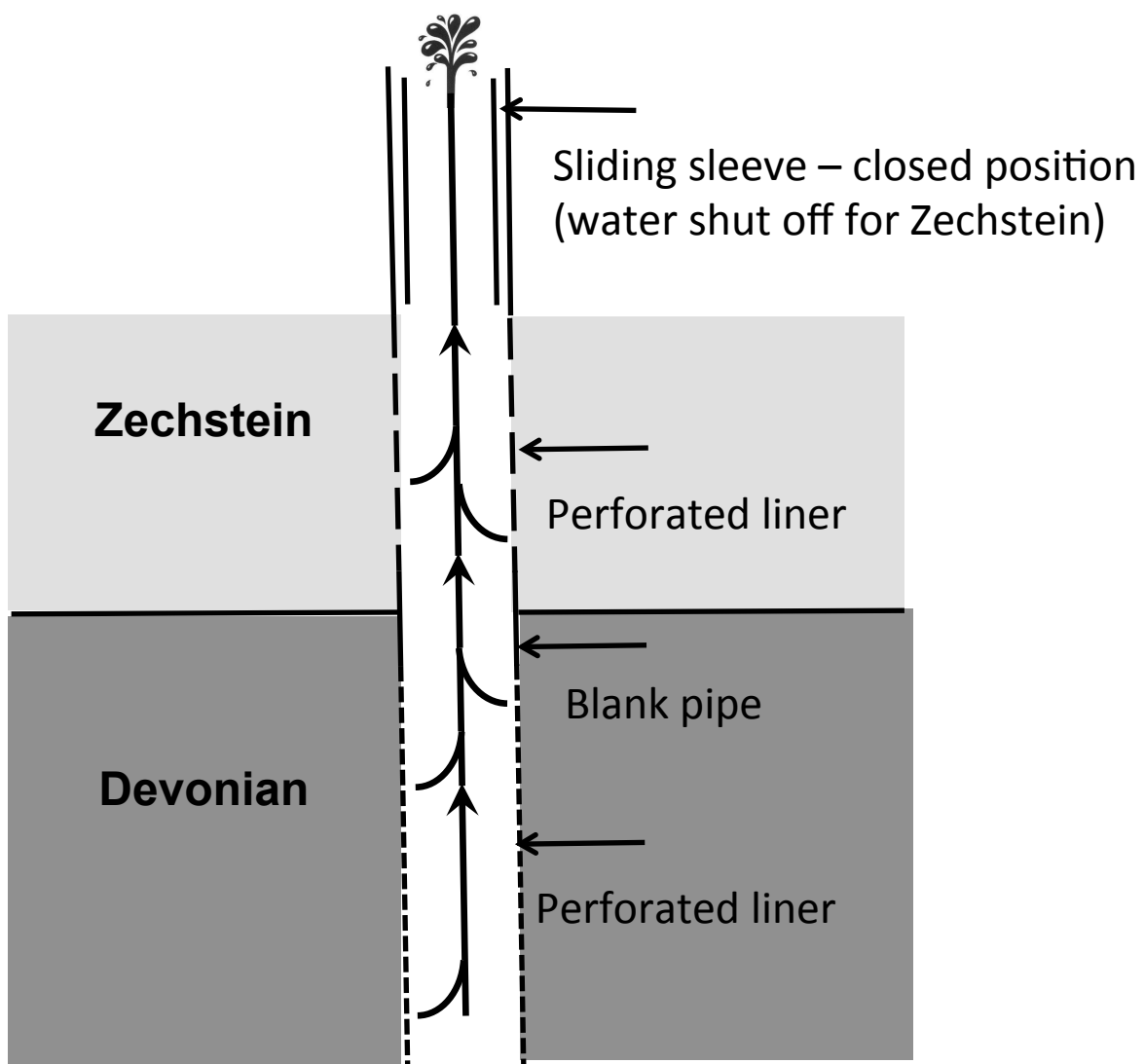


Table 1 to be added